Electric Power Supply Association
Advocating the **power** of competition

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VIA EMAIL

September 21, 2005

David H. Meyer
Acting Deputy Director
Office of Electricity Delivery and
Energy Reliability
U.S. Department of Energy
Washington, D.C. 20585

Re: **Energy Policy Act of 2005, Section 1234**
Economic Dispatch Study

Dear Mr. Meyer:

Enclosed please find the response of the Electric Power Supply Association in the above-referenced proceeding. Also enclosed is a separate paper on the consumer value of economic dispatch prepared by EPSA.

Respectfully submitted,

Tara S. Ormond

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Policy/Research Assistant

ENERGY POLICY ACT OF 2005, SECTION 1234
ECONOMIC DISPATCH STUDY

QUESTIONS FOR STAKEHOLDERS

RESPONSE OF THE ELECTRIC POWER SUPPLY ASSOCIATION

1) *What are the procedures now used in your region for economic dispatch? Who is performing the dispatch and over how large an area?*

   The individual utilities, Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) will provide the necessary detail for their individual regions. From a global perspective, all systems use security-constrained economic dispatch algorithms that match the lowest-cost resources needed every hour of every day to reliably serve demand.

   In those regions where the grid is managed by RTOs or ISOs, the algorithm is bid-based. In regions without RTOs, the utility control area operators manage the function. The process is otherwise the same, with two exceptions: 1) utility-oriented economic dispatch is cost-based (which normally includes at least a small profit), rather than bid-based; and 2) in some utility systems – unless the utility has pre-purchased non-utility generation through a bilateral arrangement that includes the right to dispatch that generation – the utility-owned generation is economically dispatched first, and then the non-utility generation is economically dispatched on an as needed basis.

   This means that utilities in regions without organized markets will economically dispatch their own generation and will economically dispatch nonutility generation if they control that generation through a bilateral arrangement. For nonutility generation, the absence of bilateral contracts results in a sequential approach to dispatch, which means that more costly, less-efficient utility owned generation can be operated ahead of less costly, more efficient non-utility generation.

2) *Is the Act's definition of economic dispatch appropriate? Over what geographic scale or area should economic dispatch be practiced? Besides cost and reliability, are there any other factors or considerations that should be considered in economic dispatch, and why?*

   The definition is appropriate. EPSA would add the following (**in boldface type**) to give the definition more specificity and clarity: "The operation of **all** generation facilities in **an identified utility or market region** to produce electrical energy at the lowest cost to reliably serve customers, recognizing any operational limits of generation and transmission facilities."

For informational purposes, PJM defines economic dispatch as: "The optimization of the incremental cost of delivered power by allocating generating requirements among the on-control units with consideration of such factors as incremental generating costs and incremental transmission losses."[1]

Duke Energy uses this definition: "The process of determining the desired generation level for each of the generating units in a system in order to meet customer demand at the lowest possible production cost, given the operational constraints on the system."[2]

Both are accurate, as are EPSA's revisions to the EPAct definition. Economic dispatch, as defined here, should be practiced throughout the United States in an unbiased, non-preferential manner across all utility single- or multi-control area systems and across all market regions.

Assuming that operational and security limits of transmission and generation facilities are inherent in the reliability component of economic dispatch, then cost and reliability are the factors that should be considered in the assessment. Another factor that is considered is environmental impact, which is manifested when sulfur dioxide and nitrogen oxides emissions must be accounted for in dispatch operations. Because some units have air permits that limit the number of hours a unit can operate in a given year, this factor must be accommodated when determining whether to commit and dispatch a unit.

3) *How do economic dispatch procedures differ for different classes of generation, including utility-owned versus non-utility generation? Do actual operational practices differ from the formal procedures required under tariff or federal or state rules, or from the economic dispatch definition above?*

For the purposes of this document, utility-owned generation means that generation built or acquired by an incumbent utility that is either placed in the rate base or treated as a cost-based asset for rate recovery purposes. Non-utility generation in the context of this study is that generation owned by parties other than the incumbent utility (inclusive of generation owned by the incumbent utility's affiliate) that is not subject to cost recovery through the utility's rate base, but is eligible for inclusion in the utility's (or its related control area operator's) economic dispatch protocols. Such competitively owned generation is also eligible for inclusion in an RTO's or ISO's economic dispatch protocols.

Actual practices differ from the economic dispatch definition(s) above when a non RTO/ISO region has a dearth of forward bilateral transactions between utility load-serving entities and nonutility generators. Such contracts allow the nonutility

[1] PJM Manual 35: Definitions and Acronyms; Revision 07; Effective Date: June 23, 2005

[2] Duke Energy Glossary of Terms; http://www.duke-energy.com/company/energy101/glossary/

generation to be scheduled, committed and dispatched economically with the utility generation.

However, some utilities have been reluctant to enter into forward bilateral contracts; as a consequence, they economically dispatch only their own generation in the first instance of need. It is this lack of forward bilateral activity that creates the sequential dispatch problem identified above when utility generation is economically dispatched first and then non-utility generation is called upon, at or near real time, to be economically dispatched after utility options are exhausted.

4) *What changes in economic dispatch procedures would lead to more non-utility generator dispatch?*

In non-RTO regions, ensure that all available and eligible generation, regardless of ownership, is simultaneously considered for merit order economic dispatch. The way to accomplish this is to ensure that regulators foster a bilateral forward market for supply contracts between LSEs and wholesale suppliers beyond the utility or its affiliate.

Regulators should make it clear that an explanation will be expected when the utility chooses to economically dispatch its own generation when other, cheaper generation supply was available. Bilateral contracts in forward markets, and not just spot markets, should be the enabler of both wholesale market development and economic dispatch that more fully utilizes nonutility generation.

5) *If economic dispatch causes greater dispatch and use of non-utility generation, what effects might this have – on the grid, on the mix of energy and capacity available to retail customers, to energy prices and costs, to environmental emissions, or other impacts? How would this affect retail customers in particular states or nationwide?*

The North American Electric Reliability Council's (NERC) 2005 Long-Term Reliability Assessment identifies 55,290 megawatts of Uncommitted Resources in the continental United States.[3] These Uncommitted Resources are nonutility megawatts that do not have bilateral forward contracts with utilities or firm transmission service. Right now, most of those megawatts are not dispatched on a full economic dispatch basis, and the units operate at relatively low capacity factors, especially in comparison to other existing generation in those regions. The impact on the grid from greater dispatch of these resources would be an infusion of lower heat-rate, less polluting and more resource-conserving electricity supply.

[3] North American Electric Reliability Council; 2005 Long-Term Reliability Assessment; September 2005; page 21.

The impact on the mix of energy and capacity available would be an increase in available natural gas-fueled generating capacity, but a decrease in actual natural gas consumed for generation, as well as a decrease in air pollutant emissions. The principal reason for the reduction in required fuel supply is that more efficient gas-fueled generation would displace less efficient gas-fueled generation. It is estimated that efficient dispatch could result in almost 700 billion cubic feet per year of natural gas savings by 2010.[4]

Under full economic dispatch of non-utility generation, wholesale costs in some regions would decline modestly because only older gas-fueled generation would be displaced in the near term. Retail customers in the affected states would benefit from lower costs and lower emissions.

6) *Could there be any implications for grid reliability – positive or negative – from greater use of economic dispatch? If so, how should economic dispatch be modified or enhanced to protect reliability?*

Because economic dispatch recognizes all transmission and generation limitations, the effect of an increase in economic dispatch on operating reliability would be neutral. Economic dispatch is accomplished on a security-constrained basis and, just as with dispatch of utility-owned generation, voltage, thermal and stability limits would be maintained in a system where all generation was dispatched economically.

Increased economic dispatch, however, could help improve grid reliability from a supply adequacy standpoint. The reason is that greater utilization of the 55,000 megawatts described above would mean that a significant fraction of those megawatts would move from the “Uncommitted Resources” category in NERC’s long-term assessment to the “Planned Capacity Resources” category. This change would have the effect of substantially improving reserve margin and capacity margin calculations because only planned capacity resources are considered in a reliability region’s reserve and capacity margin calculations.

For instance, if one-half of the 41,000 megawatts of uncommitted capacity in the Southeast Electric Reliability Region (SERC) were contracted to serve demand and given firm transmission status, then SERC’s summer 2006 reserve and capacity margins would increase from 11.6 percent and 10.4 percent to 24.1 percent and 19.4 percent, respectively.

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[4] Narrative Summary of Natural Gas Price Reduction Act of 2005 – Key Provisions; Senator Lamar Alexander (R-TN); April 7, 2005; page 5.

September 21, 2005

Respectfully submitted,

Nancy Bagot, Vice President of Regulatory Policy
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